R8490-16F 11/27

ACID RAIN
AND THE EASTERN
HIGH-SULFUR COAL INDUSTRY

September 1987

Wesley Warren
Northeast-Midwest Institute
218 D Street, S.E.
Washington, D.C. 20003
(202) 544-5200

NORTHEAST-MIDWEST CONGRESSIONAL COALITION
NORTHEAST-MIDWEST SENATE COALITION
NORTHEAST-MIDWEST INSTITUTE

In late 1976, members of Congress from the region founded the Northeast-Midwest Congressional Coalition in recognition of the common problems facing their states and the fact that federal policies often create major obstacles to regional economic growth. The bipartisan group now includes nearly 200 members of the House of Representatives. The Northeast-Midwest Senate Coalition, which was formed in 1978, has 36 members. Together the Coalitions seek to inform their members about the regional implications of national policies and proposals, and to influence those issues of greatest importance to Northeastern and Midwestern states.

The Coalitions propose legislative solutions to the economic problems of the New England, Mid-Atlantic, and Midwest states, and work to assure that federal policies are equitable in their treatment of different areas of the country. Task forces help develop policy initiatives and positions on subjects ranging from the federal budget and economic development to defense, natural resources, energy, and transportation.

The Northeast-Midwest Institute was formed in 1977 at the request of members of the House and Senate who perceived the need for information and analysis of public policies to identify and further the interests of the region. The Institute seeks to encourage policies that will ease the pressures on and support the continued revitalization of the region's economy. It continually searches for new ideas and legislative options that can help older Northern states overcome their handicaps--such as high energy costs and a deteriorating infrastructure--and prudently develop their many assets, including a highly skilled work force, top quality educational institutions, and abundant natural resources.

Although members of Congress remain key clients of the Institute, the organization has developed close working relationships with governors, mayors, and other state and local officials as well. The Institute's work is used widely and relied upon by corporate and labor leaders, academics, public interest groups, associations, and journalists throughout the nation.

The states in the region served by the three organizations are Connecticut, Delaware, Illinois, Indiana, Iowa, Maine, Maryland, Massachusetts, Michigan, Minnesota, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, Vermont, and Wisconsin.

Funding for this report was provided through the generous support of the William and Flora Hewlett Foundation, the George Gund Foundation, the Fund for New Jersey, and the Alida Rockefeller Dayton Trust.

Executive Summary

Emissions of sulfur oxides (SOx) that contribute to acid rain primarily come from industries and power plants that burn high-sulfur coal. There are two principal methods for controlling SOx: a facility can either switch from coal with a high-sulfur content to low-sulfur coal, or it can use technology to remove the sulfur. The economic effects on the Eastern high-sulfur coal region of reducing emissions could be greatly lessened if an acid rain control program relied on cost-effective technologies rather than large-scale coal switching.

High-sulfur coal in the U.S. is found mainly in Eastern states, whereas almost all of the coal in the West has a low-sulfur content. The Eastern high-sulfur coal industry has been declining for several years, steadily losing production to low-cost Western producers. Controlling acid rain through coal switching would accelerate this trend, causing a loss to Eastern coal states of thousands of coal mining jobs and billions of dollars in annual income.

Compared to switching, the use of technology to control acid rain would benefit the Eastern coal region in two ways. First, it would protect the Eastern high-sulfur coal industry by using coal in an environmentally acceptable manner. Second, it would expand employment among manufacturers of pollution control equipment, many of which are located in the industrial coal states.

Although the main control technologies in current use are effective at controlling emissions of SOx, they are generally more expensive than switching. Therefore, special consideration should be given to how the role of technology can be expanded in any acid rain control plan. This paper outlines three provisions designed to maximize the cost-effective use of control technologies:

- Establish a special acid rain control fund to promote technology. This fund would provide subsidies for the use of scrubbers in the early years, and finance a major clean coal technology program for the development of less expensive control methods for later years.

- Subsidize the use of scrubbers at the most cost-effective units. In the early years of the program, financial incentives would be offered for installing scrubbers. By allowing utilities to choose to scrub, instead of mandating their use, scrubbers would be installed only where they were cost-effective. By providing subsidies only in the early years, a quick clean up would be encouraged.

- Phase in controls at all other units according to their age. A phase in of controls would allow time for research efforts to complete the development of new, cost-effective clean coal technologies. Often the least expensive time to install an innovative control technology is when a unit extends the life of the plant or expands its power output. Therefore, bringing a unit under control when it turns a certain age could minimize the cost of controls and encourage compliance through the use of innovative technologies.

Introduction

Electric utilities and industries that burn fossil fuels emitted more than 26 million tons of sulfur oxides (SOx) into the air in 1980. These emissions are transformed in the atmosphere into acidic compounds known as acid rain. Prevailing winds, blowing generally in the northeasterly direction, deposit acid rain long distances downwind, where it damages lakes and building materials, and possibly forests and human health.

The Clean Air Act currently sets standards to regulate SOx emissions. New Source Performance Standards (NSPS) require a strict percentage reduction in emissions from units built after 1977. Older sources are controlled by ambient standards set by state implementation plans that prevent concentrations of specified pollutants, such as SOx, from exceeding certain levels locally.

When the Clean Air Act was approved, lawmakers expected old power plants to retire after about 30 years of operation and to be replaced by new, clean power plants regulated under NSPS. Because the costs of building new power plants have soared, however, utilities are extending the lives of their old plants, often by an additional 30 to 40 years. Much of the current acid rain debate focuses on the need to regulate emissions from these older sources.

This paper concentrates on ways to control sulfur oxides (SOx) rather than nitrogen oxides (NOx), a pollutant of increasing concern in the acid rain debate. Neither switching nor scrubbing would control emissions of NOx, but most utilities could control them economically by installing conventional low-NOx burners. However, an important exception to the use of low-NOx burners is the cyclone boiler, which predominates in Illinois. Therefore, a control technology that controlled both SOx and NOx from cyclone boilers would be especially beneficial.

To control emissions of SOx from burning high-sulfur coal, utilities and industries could either switch to a lower-sulfur fuel or use technologies that remove the sulfur. This paper focuses on the effects of switching from high-sulfur to low-sulfur coal, although switching to other clean fuels such as natural gas could also occur.

The main technology for controlling SOx has been flue gas desulfurization, known as scrubbing. While scrubbers effectively remove SOx, they can be expensive and may require significant electricity rate increases. However, a new generation of clean coal technologies under development could control SOx at a much lower cost than conventional scrubbing.

One form of federal assistance for technologies would be subsidies large enough to equalize the difference in cost between switching and scrubbing. Such subsidies could induce utilities to scrub voluntarily. Federal assistance also could be given through a major program to complete the development of cost-effective, innovative control technologies. If these promising technologies reduce the costs of controls enough, they could compete directly with coal switching. A combination of the two forms of federal assistance would give the most powerful boost to the use of technologies.

The Condition of the Eastern High-Sulfur Coal Industry

Three main coal-producing regions exist in the U.S. -- the Appalachian, Interior, and Western regions. The average sulfur content of the coals produced in these regions varies significantly. Western coal has a low-sulfur content, Interior coal has a high-sulfur content, and Appalachia produces high-sulfur coal in the northern range and mid-to-low sulfur coal in the southern part (see map).

Shift from East to West

Electric utilities are the main customers of U.S. coal producers, consuming 76 percent of total production in 1985. Utilities have been shifting their purchases steadily in favor of Western coal producers. Between 1980 and 1985, for instance, utilities increased their consumption of Eastern coal by 11 million tons, compared to an increase of 61 million tons in Western coal. Percentage changes are even more stark: production growth in the East amounted to less than 3 percent, while it topped 32 percent in the West (see Table 1).

It has been noted that much of the growth in Western coal production is due to an increase in new coal-fired electricity capacity in Western states, where demand for local coal has grown significantly.[1] However, a market analysis by Northeast-Midwest indicates that Western coal producers also have invaded coal markets historically supplied by the East.

In 1980, Western coal producers supplied only one fourth of the coal consumed by electric utilities in the East. Although coal consumption by Eastern and Western utilities increased by approximately equal amounts between 1980 and 1985, when measured in net aggregate terms, Western producers supplied all of the increase in the West and two-thirds of the increase in the East. Altogether, the net shipment of Western coal to Eastern markets grew from 114 million tons to 143 million tons during this period.

Loss of Eastern Competitiveness

A major cause of the decline of Eastern coal is that it is simply becoming more expensive than Western coal in many markets.[2] This loss of Eastern coal competitiveness is due in large part to the rapid advance of Western coal mining productivity. Although coal mining productivity between 1980 and 1985 increased by 37 percent in the Appalachian region and 22 percent in the Interior region, in the West it increased by 52 percent (see Table 2).

The plight of Eastern coal producers has been paralleled by a drop in employment in the Eastern coal fields. Between 1980 and 1985, Eastern coal-mining employment sharply declined by 56,500, or 27 percent. Because the dominant production method in the West -- strip mining -- is relatively capital-intensive, the shift in relative market shares from Eastern coal to Western coal translated into a net decrease in national employment for coal miners (see Table 3).

Drop in Potential Emissions

One consequence of the shift has been a reduction in the average sulfur content of coal burned by U.S. utilities. If the coal consumed in 1985 had contained the same average sulfur content as that in 1978, emissions of SOx would have been up to five million tons a year higher[3] (see Tables 4 and 5).

Consider the experience in Michigan, where the sulfur content of utility coal dropped from 1.84 percent in 1980 to 0.80 percent in 1985. As a result, the potential emissions of SOx from Michigan utilities declined nearly 500,000 tons per year between 1978 and 1985.

The Possibility for Future Coal Switching

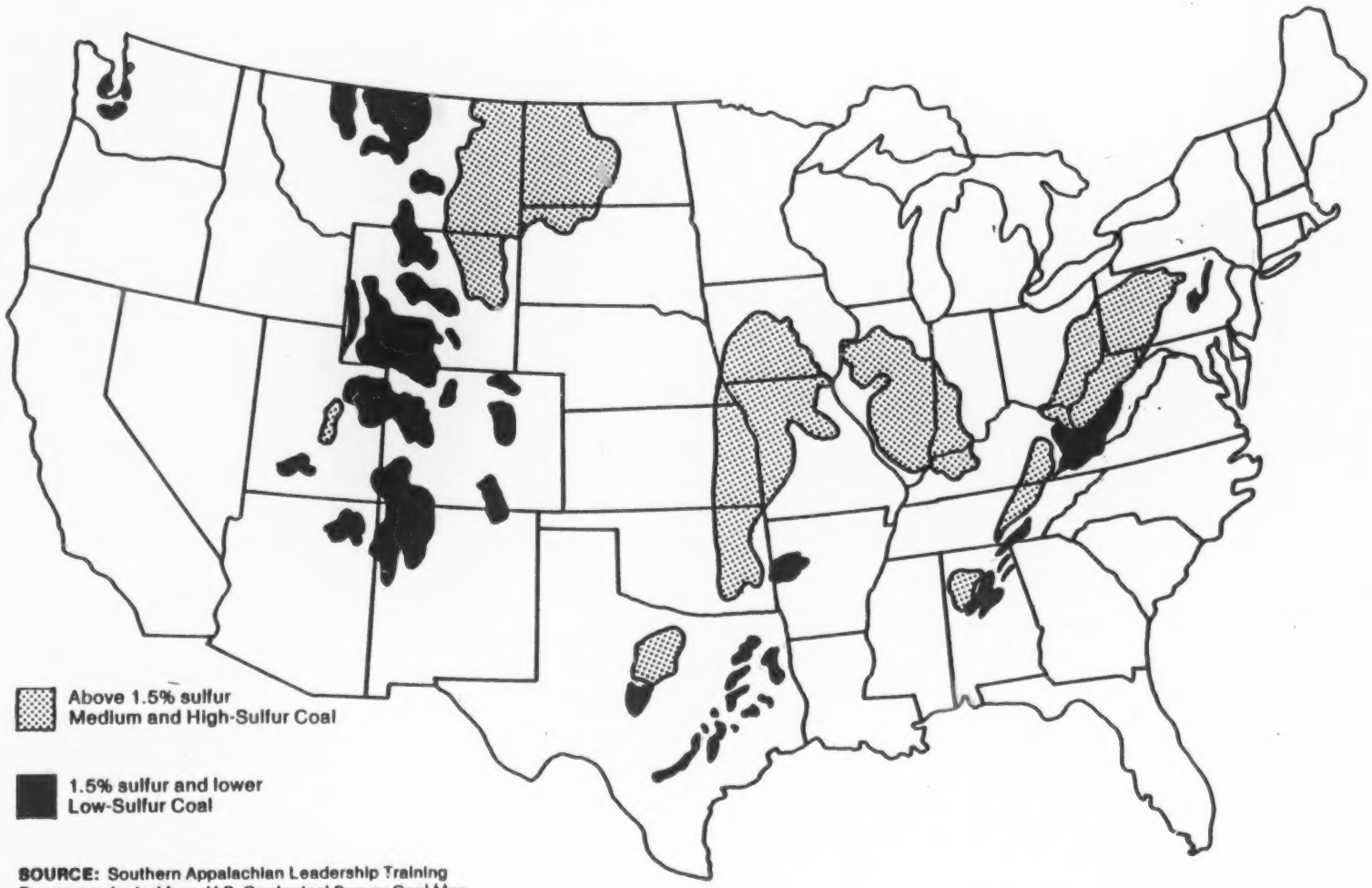
While both Eastern high-sulfur coal producers and utilities oppose acid rain controls, their motives are different. Producers want to maximize production, but utilities want to minimize costs. If controls were approved, coal producers would want utilities to use technologies that control emissions from high-sulfur coal, while utilities would want the freedom to choose the least costly method of control.

Similar differences occur among the states. With acid rain controls, coal-producing areas may choose to continue burning their high-sulfur coal with control technologies, while coal importers would select the least-expensive control methods that meet the emission standards. Therefore, Eastern coal-exporting states, Illinois, Kentucky, Pennsylvania, and West Virginia, are the most vulnerable to the effects of coal switching (see Tables 6 and 7).

Given current technology, the extent of coal switching under acid rain controls would depend largely upon the costs of switching compared to scrubbing. Many analysts believe that these relative costs will be determined mainly by the extent of the "low-sulfur coal premium". A higher price, they argue, would be imposed by coal producers at the mine-mouth and by coal transporters, mainly railroads, in response to the increase in demand for low-sulfur coal. Although opinions differ on the probable size of a low-sulfur coal premium, theoretically, it could be as high as the costs of alternative controls.[4]

Defenders of coal switching contend that reserves of low-sulfur coal are large enough to prevent supply bottlenecks. They also claim that real rates for coal transportation have not increased drastically since the railroads were deregulated. Price increases, of course, could occur for individual utilities or industries, particularly if the coal burner were held "captive" to a single transportation line. In these cases, the availability of economical control alternatives would offer some protection.

Distribution of Coal Reserves by Sulfur Content



SOURCE: Southern Appalachian Leadership Training Program, adapted from U.S. Geological Survey Coal Map.

NOTE: Approximate location of the high and low sulfur coalfields in the U.S.

There are two main questions concerning acid rain control legislation:

- Who should pay?
- What kind of regulations should be used?

Who should pay for acid rain controls? The typical debate is between proponents of "national cost sharing" and advocates of "polluter pays." Supporters of national cost-sharing argue that acid rain is a national environmental problem with implications for long-term energy development and balanced economic growth. While "polluter pays" is an attractive principle, in the case of acid rain it overlooks the fact that coal miners, rather than the utility polluters, would be forced to pay by losing their jobs.

What regulatory strategy should be used? One major approach would be to mandate a particular control method for utilities, such as mandating scrubbers. Another more popular approach would be to permit utilities the freedom to select a method, thus allowing the market to operate more fully. Given the current costs of control technologies, however, the "freedom of choice" approach becomes a euphemism for coal switching. Therefore, combining freedom of choice with national cost sharing for technologies may be the best way to minimize losses to the Eastern coal industry.

	FINANCING METHOD:	
REGULATORY STRATEGY:	National Cost Sharing	Polluter Pays
Freedom of Choice	Protects Eastern coal, and gives utilities flexibility	Gives utilities flexibility, but affects Eastern coal.
Forced Scrubbing	Protects Eastern coal, but restricts utility flexibility.	

Legislative History

Congress has had difficulty finding an acid rain control strategy that avoids the scrubbing-switching dilemma. Many past congressional proposals, especially in the Senate, have taken the "polluter pays" position, requiring utilities to reduce emissions without providing financial assistance for controls. Other approaches have offered financial assistance through national cost-sharing that would levy a national tax and provide subsidies.

H.R. 3400 in the 98th Congress, defeated in subcommittee by one vote, was the original piece of legislation to propose national cost-sharing. H.R. 3400 would have required the top 50 emitting utilities to use scrubbers to protect

high-sulfur coal production, but would have provided subsidies to help reduce the impact on electricity rates. Although the use of nationally cost-shared subsidies was controversial, much of the opposition to this bill stemmed from a reluctance to force a particular control method on utilities.

In the House in the 99th and 100th Congresses, there has been a move away from mandating scrubbing and giving subsidies. H.R. 2666 in the current Congress is based largely upon H.R. 4567 from the 99th. H.R. 4567, which was awaiting action by the full committee when Congress adjourned, completely dropped scrubber requirements and relied instead on a freedom-of-choice approach. The use of subsidies also was greatly restricted to only those cases where electricity rate increases exceed 10 percent.

The principal features of H.R. 2666/H.R. 4567 that would affect the Eastern coal region are:

- STATE PLANS — States would be required to implement plans to reduce utility SOx emissions to an average rate of 2.0 pounds per million BTU in five years and 1.2 pounds per million BTU in ten years.

- DEFAULT PLANS — Failure to implement a state plan by the required deadlines would result in the imposition of the emission limits on individual sources within the state.

- FREEDOM OF CHOICE — Plants producing emissions would be allowed to select any method of control.

- NATIONALLY COST-SHARED SUBSIDIES — Utilities would receive subsidies in cases where average residential electricity rate increases exceed 10 percent. It would be financed through a national fee on the generation of electricity.

Although H.R. 2666 is the leading bill currently before the House, this report focuses attention on H.R. 4567 since the bills are so similar and more extensive information is available on H.R. 4567.

Projected Effects of H.R. 4567

Three major studies have been done by or for the federal government on the economic impacts of H.R. 4567. The Congressional Budget Office (CBO) and ICF, Inc., for the Environmental Protection Agency, calculated changes in utility costs and employment in the high-sulfur coal region, especially the four-state region of Illinois, Indiana, Ohio, and Pennsylvania. These two reports and a third by the Office of Technology Assessment (OTA) estimated the impact of H.R. 4567 on electricity prices.[5]

The main difference between H.R. 4567 and H.R. 2666 is that H.R. 4567 would require an annual reduction of about 9 million tons of SOx below 1980 levels, while H.R. 2666 would reduce SOx by 10 million tons. Generally CBO, ICF, and OTA agree that the unit costs of an acid rain program (costs per ton of SOx removed or costs per kilowatt hour of electricity generated) increase with the level of reduction, rising steeply between 10 million and 12 million tons.

CBO provides typical estimates: costs of removing SOx rise from $270 per ton for 8 million tons, to $360 for 10 million tons, to $799 per ton for 12 million tons. In other words, average control costs increase by less than half between 8 and 10 million tons, but more than double between 10 and 12 million tons (see Tables 8, 9, and 10).

The level of reduction selected would affect the choice of control methods. Most utilities could meet reductions lower than 10 million tons a year by switching to low-sulfur coal, but would have to resort increasingly to scrubbers for reductions over 10 million tons. Thus, the Eastern coal industry might lose less production under the stricter 12-million ton proposal, even though total costs of control for utilities would rise sharply.

These studies concurred that, given current technology, the least expensive way for most states to comply with H.R. 4567 would be to switch to low-sulfur coal. None of these studies calculated the potential benefits of using clean coal technologies rather than scrubbing or switching. ICF, for example, stated that its analysis "assumed that new sulfur control technologies ... would not be available. For this reason, the costs of SOx controls may be overstated to the extent such technologies would be available in the future on a large scale."[6]

Utility Costs

Comparisons of cost estimates by the researchers are complicated by their use of different baselines and assumptions. Still, both CBO and ICF estimated that the annual national costs to utilities of controlling SOx under H.R. 4567's state plans would be $2.5 billion. Imposition of default plans would raise the costs to $3.3 billion a year, according to CBO; ICF estimated a higher $5.5 billion (see Tables 11 and 12).

Although cost projections vary for individual states, the four-state region of Illinois, Indiana, Ohio, and Pennsylvania would bear the brunt of national SOx control program. CBO estimated the annual regional costs under state plans would reach $1.03 billion, or 40 percent of the national total. ICF projected a regional expense of $1.26 billion, or 51 percent of the national total. In addition, ICF calculated that controlling NOx would cost the region $175 million, with most of the expense falling on Illinois.

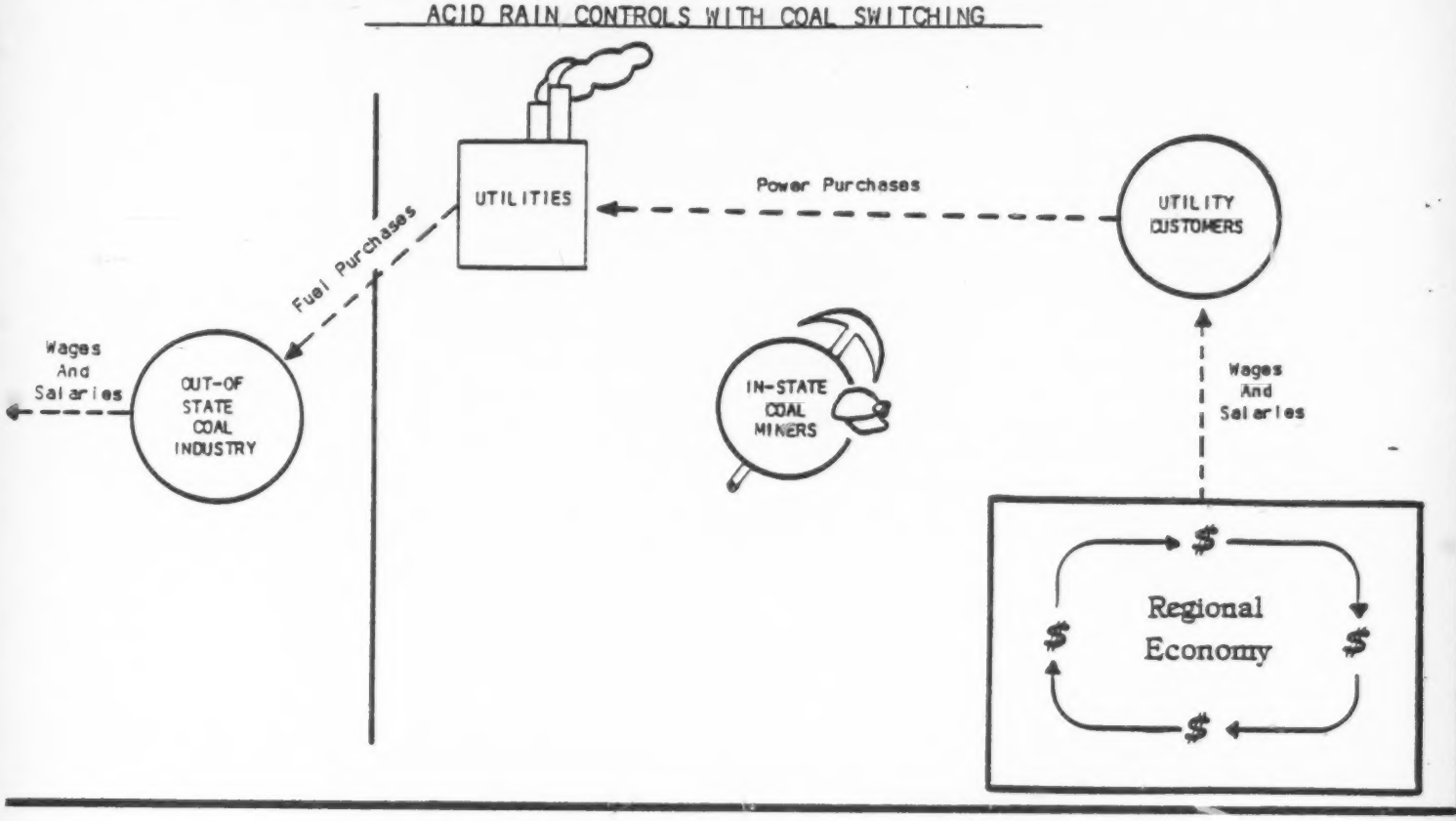
H.R. 4567, as stated above, would have provided subsidies to utilities in states experiencing electricity rate increases above 10 percent. OTA and ICF agreed that only Indiana and Ohio would be eligible under a default plan. CBO predicted no rate increases over 10 percent (see Table 13).

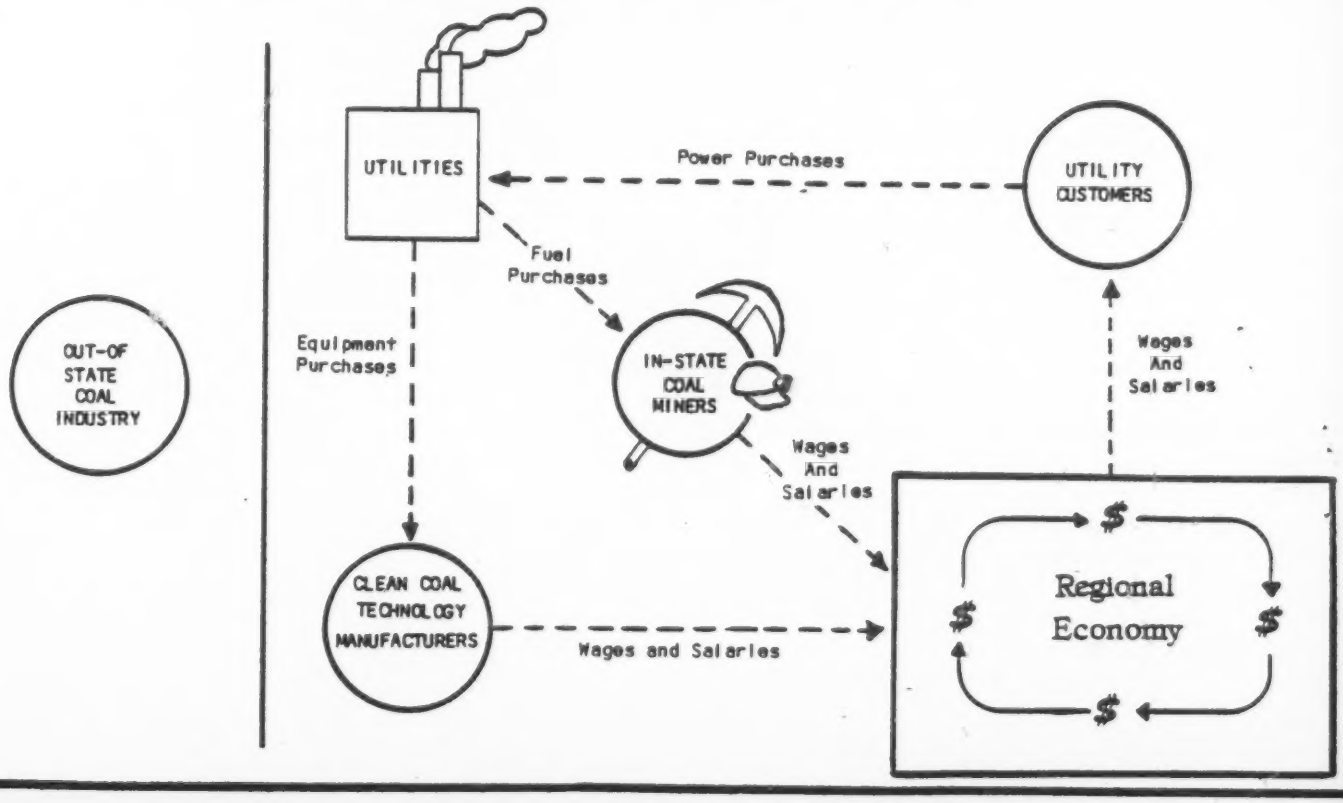
Employment

In response to H.R. 4567, most utilities would have controlled emissions by coal switching, transferring coal production from northern Appalachia and the Midwest to central Appalachia and the West. ICF estimated production in northern Appalachia and the Midwest by the year 2000 would fall 22 percent, a decline from 393 million tons to 309 million tons. Production would rise by 33 million tons in central Appalachia, and 49 million tons in the West.

Most employment losses would occur in the four-state region of Illinois, Indiana, Ohio, and Pennsylvania. CBO projected that these states would lose

Effect of Acid Rain Controls on Flow of Regional Income





nearly 17,000 coal-mining jobs by 1995. A study by the United Mine Workers (UMW) produced similar results, estimating job losses at 19,000 in the four-state region. CBO and UMW, however, disagreed about the bill's impact on the coal industry in West Virginia. CBO projected a net gain of 14,500 jobs, due to the availabilty of low-sulfur coal in the southern part of the state, while UMW only counted the 7,200 high-sulfur coal jobs that would be lost (see Table 14).

Transfer of Regional Income

Large-scale coal switching would cause a significant shift of income from high-sulfur coal states in the East to low-sulfur coal states in the West. Although it is difficult to estimate this shift precisely, the most direct method would be to multiply anticipated declines in state coal production by current coal prices. This method shows that if utilities in the Eastern states switch to other coal sources, the four states of Illinois, Indiana, Ohio, and Pennsylvania would lose at least $2 billion annually. Wyoming, by comparison, would gain more than $1 billion annually (see Table 15).

By contrast, if utilities used technologies to control emissions, income from high-sulfur coal production could be preserved. Furthermore, if control technologies were used, Northeastern and Midwestern states would benefit from the manufacturing of pollution control equipment. According to figures from the Air Pollution Control Association, about two-thirds of the U.S. manufacturers of air pollution control equipment are located in the Northeast-Midwest region, with nearly one-fourth of them in the three states of Illinois, Ohio, and Pennsylvania. In addition, Kentucky, Ohio, and Pennsylvania are major producers of lime, used to remove SOx from emissions. Reliance on technology to control pollution, therefore, would help recycle income within the Eastern coal region, whereas coal switching would produce a net drain (see chart).[7]

Distribution of Manufacturers of Air Pollution Control Equipment in 1984 by State

Connecticut	19	New Hampshire	4
Delaware	4	New Jersey	67
Illinois	40	New York	67
Indiana	5	Ohio	39
Iowa	5	Pennsylvania	65
Maryland	10	Rhode Island	2
Massachusetts	42	Wisconsin	12
Michigan	37		
Minnesota	14	Northeast-Midwest	432
		U.S.	636

SOURCE: Northeast-Midwest staff calculations from Air Pollution Control Association, Product Guide/1984.

The Potential Role of Control Technologies in Controlling Acid Rain

This section outlines a policy designed to maximize the use of technology under an acid rain control plan. Current control technologies are capable of effectively controlling emissions of SOx, but can be expensive and often may not be able to compete with coal switching as a control method (see Appendix A). Innovative clean coal technologies may be able to substantially lower the costs of controls but are still under development. Successfully using technology to control acid rain, therefore, will depend upon promoting the selective use of conventional technologies where they are cost-effective with a timely phase in of new, clean coal technologies as they become available.

Current Control Technologies

Most control technologies fall into one of three categories: pre-combustion, combustion, and post-combustion.[8] Pre-combustion technologies prepare coal for burning, combustion technologies clean up emissions as the fuel is burned, and post-combustion controls remove emissions from gases in the stack or ductwork.

The main technology currently available for controlling SOx is a post-combustion device known as a scrubber. In addition, a certain amount of pre-combustion coal cleaning is being done, often to remove ash or increase the quality of the coal as well as to remove SOx.

Innovative Clean Coal Technologies

The projected costs and capabilities of new, clean coal technologies vary widely, but many of them are expected to compare favorably with conventional scrubbing (see Table 16). Innovative technologies differ from one another according to whether they will be used as retrofits or for repowering (see Appendix B), a distinction explained in greater detail in the following section. The appropriateness of an innovative technology usually depends upon the age and size of a unit's boiler.

Retrofitting

Retrofit technologies are used solely for the purpose of emission control and could play a major part in controlling acid rain. Three of the most promising examples of innovative retrofit technologies are advanced physical coal cleaning (pre-combustion), LIMB (combustion), and duct injection (post-combustion). For example, combining coal cleaning with duct injection could remove 70 percent of SOx emissions at half the costs of conventional controls.[9]

Repowering

Repowering is the reconditioning of a power plant, usually by replacing its boiler or adding turbines, that increases electricity capacity or extends the life of the unit. Repowering technologies include fluidized bed boilers

(combustion) and integrated gasification combined cycle (IGCC). IGCC, strongly supported by the Electric Power Research Institute (EPRI) as one of the main electric-generating technologies of the future, actually is a combination of several clean coal technologies--gasification, hot-gas cleanup, and heat engines. IGCC produces both a high plant efficiency and few emissions.[10]

Designing a Technology Approach

Utilities argue that acid rain controls with stringent deadlines would not allow sufficient time to develop innovative technologies, locking them into choosing between scrubbing or switching. Environmentalists, on the other hand, claim that utilities will not develop new technologies until they are forced to comply with new pollution-control requirements. It may be possible, however, to design a control program that encourages the use and development of cost-effective technologies while significantly reducing emissions.

To maximize the use of control technology, an acid rain control plan should have three parts:

- subsidies in the early years for the use of scrubbers on units where they are cost-effective;
- a major research program to develop low-cost, innovative technologies; and
- a phase in of controls on other units in later years as innovative technologies become available.

Part 1: Subsidies for the Selective Use of Scrubbers

The most direct way to ensure that control technologies are used to control emissions would be to provide subsidies for their installation. To be cost-effective, subsidized scrubbing should be offered as an option at the most appropriate units but should not be required. Thus, a selective scrubbing strategy relies on incentives to induce utilities to choose to scrub instead of switch, and therefore would differ from mandating scrubbers.

H.R. 3400 would have mandated that the 50 power plants that were the top emitters of SOx to use scrubbers, giving them subsidies to help pay for the costs. Objections were raised to H.R. 3400 in part because it would have required utilities to use scrubbers. A freedom of choice approach should be substituted instead.

An additional objection to H.R. 3400 was that the list of the top 50 emitters slated for scrubbing was defective. First, the list ranked emitters by plant, even though scrubbers are usually installed at the unit level. This method was imprecise because each plant may have several units with very different characteristics. Second, the top 50 emitters were ranked according to contribution to pollution, and not according to cost of scrubbing. Selecting units according to cost of controls could significantly lower the total costs of a program.

Our understanding of the economics of scrubbing has advanced to the point that selective scrubbing could be undertaken in a much more scientific manner than a few years ago. Incentives for selective scrubbing should be high enough

to induce the most cost-effective units to scrub, without being so high that the total costs are unreasonable. For example, incentives could be designed to pay for a certain percentage of the total costs of control, with a cap on the maximum payment. Also the incentives should only be paid in the early years of a program to encourage utilities to clean up as quickly as possible.

The total amount of emission reductions that could be achieved through selective scrubbing would be determined ultimately by the level of incentives offered under the program. A study done for EPA by Energy Ventures Analysis, Inc., revealed that units that are easy to scrub emit about 3.3 million tons of SOx a year and units that are only moderately difficult to scrub contribute another 3.0 million tons.[11]

Subsidies could be financed through the assessment of a special fee. For example, a fee of one-half mill on each kilowatt-hour of electric power generated in 1985 would have raised more than $1.2 billion and amounted to less than 1 percent of the average electricity bill in the U.S.[12] A fee on emissions has also been proposed as a method of raising revenues.

Part 2: Establishment of a Major Clean Coal Technology Development Program

Clean coal technology development has the potential to greatly reduce the future costs of controls, especially at units that are difficult to scrub. As part of any acid rain control plan, the federal government should implement a major clean coal program on the scale recommended by the Lewis-Davis report.[13] Such a program would require an average of $500 million a year for ten years to deploy innovative technologies at commercial scale. The electric power sector contends that commercial scale demonstration is necessary to assure utilities that innovative technologies will perform as expected once introduced into commercial use.

Part 3: Phasing in Controls According to a Unit's Age ("Life-Cycling")

The suitability of a particular control technology often depends upon a unit's age.[14] It is often not economical to retrofit an old unit with a control technology if the unit is not expected to have many more years of operation. In this case, it may be more economical to switch to low-sulfur coal or retire the unit altogether. Conversely, large, relatively young units can be scrubbed most economically. The most likely candidates for innovative technologies are middle-aged units that may be difficult to scrub for some reason.

There are many different ways in which acid rain controls could be phased in. H.R. 4567 would have required emission reductions in two stages: to a state average of 2.0 pounds per million BTUs in five years and to 1.2 pounds per million BTUs in ten years. The two-stage approach would have allowed utilities to switch to low-sulfur coal to meet the first deadline, but would have permitted additional time for the development of innovative technologies to meet the latter requirement.

Another approach, called "life-cycling," would require a unit to meet a certain performance standard at a specified age.[15] The most common life-cycling proposal is known as 30 years/1.2 pounds, which would require a 30-year-old unit to meet a performance standard of 1.2 pounds per million BTUs. Other standards, of course, are possible, including 40 years/1.2 pounds or 30 years/0.9 pounds.

Life-Cycling and Repowering Technologies

The economics of using a repowering technology is closely tied to a unit's life-cycle. As units approach 30 years in age, investments in life extension generally have to be made if the unit is to continue operating reliably and efficiently. Investments in expanding the power output of a unit by adding turbines or a larger boiler may occur at the same time. In many cases, the most economical time to install an innovative repowering technology may be when such reconstruction is undertaken.

Many proponents of clean coal technologies have argued that a research program to develop repowering technologies would be sufficient to solve the acid rain problem even without mandatory emission reductions. In fact, they claim that acid rain proposals that required emission reductions within ten years would preclude the final development and deployment of these promising technologies.

In one respect, the supporters of repowering may be correct. Despite the overall benefits of using repowering technologies to control emissions, their use will be limited to areas where growing electricity demand and aging power plants make incremental power expansion attractive. Unless controls are phased in according to unit life-cycle, then the number of units reaching the proper age for repowering during the compliance period could be quite small.

On the other hand, simply waiting for the utility sector to install new generating technologies at some point in the future would be an uncertain means of environmental protection. Despite the development of new technologies, utilities could decide to extend plant life with traditional methods that do not reduce emissions. Furthermore, they could use repowering technologies to reduce the costs of complying with present Clean Air Act requirements and not reduce their current emission level. In fact, developing repowering technologies without requiring net emission reductions could have the perverse effect of extending the life of plants that do not meet cleaner NSPS.

Thus, a phase in of controls according to unit life-cycle and the establishment of a major research program to develop repowering technologies go hand-in-hand. The combination could dramatically lower the long-term costs of an acid rain control plan.

Life-Cycling and Retrofit Technologies

The use of retrofit technologies is less closely tied to a unit's age than either conventional scrubbing or repowering. Innovative retrofit technologies in particular, from coal cleaning to advanced combustion, could offer flexible and cost-effective control methods for many different kinds of units. In fact, advanced coal cleaning is the universal retrofit technology capable of use at any unit and in combination with any other kind of control technology.

Even though retrofit technologies are not necessarily tied to a unit's age, phasing in acid rain controls would still be beneficial for their use. Allowing more time for research on these technologies to be completed would provide utilities with a broader selection of control options.

Timing of Emission Reductions

Life-cycling may present a low-cost method of complying with acid rain controls, but it achieves those reductions more slowly than leading congressional proposals would allow. ICF estimates that a 30 year/1.2 pounds phase in (with trading of emissions between sources) would reduce SOx emissions by 6 million tons in the year 2000.[16]

A 30 year/1.2 pounds requirement would be slow to reduce national emissions mainly because of the number of large power plants with high emission rates commissioned during the 1960s and 1970s. Coincidentally, these units generally are the ones categorized as easy to scrub in the study by Energy Ventures Analysis. If this easy-to-scrub group were regulated under a program that relied on life-cycling alone, about two-thirds of its capacity would not be controlled until after the year 2000. Therefore, it is necessary to combine life-cycling with selective scrubbing in the early years at these easy-to-scrub units if emission reductions are to be achieved quickly.

Conclusion

This paper has reviewed trends in the Eastern coal region over the last decade. The main conclusions are:

- The Eastern high-sulfur coal industry has been declining for several years. Employment in the Eastern coal industry dropped by over a fourth between 1980 and 1985. Much of decline in Eastern coal competitiveness was due to rapidly advancing productivity in Western coal fields. As a result, Western coal producers increased the amount of coal they shipped to Eastern electric utilities, displacing nearly 30 million tons of Eastern coal during this period.

- The shift in U.S. production from East to West has significantly lowered the potential emission of SOx. Western coal has a lower average sulfur content than Eastern coal. In some cases, a shift to low-sulfur Western coal was an environmental decision on the part of a coal-importing state. If the coal that utilities burned in 1985 had the average sulfur content of coal burned in 1978, potential emissions of SOx in the U.S. would have been 5 million tons greater.

- Acid rain control plans relying on coal switching to control SOx would accelerate the decline of the Eastern high-sulfur coal industry. Under H.R. 4567 in the 99th Congress, which is very similar to current proposals, significant coal switching would have occurred. The states of Indiana, Illinois, Ohio, and Pennsylvania would lose between 17,000 to 19,000 coal-mining jobs and over $2 billion in annual state income.

- Acid rain control plans that promote control technologies could greatly reduce economic impacts on the Eastern high-sulfur coal region. If the fee and subsidy section of H.R. 4567 were properly redesigned, the use of cost-effective technologies could be made more attractive to utilities. Using control technologies would have the double advantage for this region of protecting its high-sulfur coal industry and expanding employment among local pollution control industries.

Designing a Cost-Effective Technology Approach to Controlling Acid Rain

The acid rain debate presents an array of complex technical and economic issues. Further study is needed to provide reliable projections for cost and emission trends. However, it might be possible to protect the Eastern coal region by designing an acid rain control plan that would do the following:

- subsidize the use of scrubbers at the most cost-effective units in the early years;

- finance a major research program to develop innovative technologies for later years, especially those that repower aging facilities; and

- phase in controls at other units according to their age, therefore allowing the cost-effective use of innovative retrofit and repowering technologies as they become available.

APPENDIX A

COSTS OF SCRUBBING VERSUS THE COSTS OF COAL SWITCHING

COSTS OF SCRUBBING

The estimated costs of scrubbing vary widely. Not only is there a wide range of technical performance by scrubbers in actual use, the projected costs of scrubbing can be affected by many changing variables such as interest, inflation, and taxes. Examples of attempts to calculate costs include:

- Figures from the Electric Power Research Institute on the potential cost-effectiveness of wet scrubbers in removing SOx range from a low of $425 per ton to a high of $1429 per ton, with capital costs of $157 to $492 per kilowatt of capacity. Excluding the Wellman-Lord systems, most of the scrubbers fall in the range of $500 to $1000 per ton.[17]

- In a study by American Electric Power that used an EPRI cost model, the range of estimated capital costs was $228 to $366 per kilowatt with annual operating and maintenance expenses of $34 to $46 per kilowatt (1986 dollars).[18]

- A 1985 study by the Tennessee Valley Authority expected the retrofit of wet limestone scrubbers to cost $185 per kilowatt to install and 3.4 mills per kilowatt hour to operate, for total annual costs of 10.1 mills per kilowatt-hour. (Wet scrubbers tend to be more expensive than dry scrubbers, but generally have higher removal efficiencies with high-sulfur coal.) Cost-effectiveness of SOx removal would be $723 per ton (1985 dollars).[19]

- A recent report by the Industrial Gas Cleaning Institute challenged utility projections of the cost of scrubbing and concluded that actual costs of installing a wet scrubber would be between $150 and $160 per kilowatt with annualized capital and operating costs in the first year of 5 to 6 mills per kilowatt-hour.[20]

- Operational data from DOE on scrubbers that have been retrofitted on plants using high-sulfur coal offer a range of capital investments of $60 to 210 per kilowatt (see Table 17).

- A 1986 CBO study placed the costs of scrubbing a 500 megawatt plant at $240 per kilowatt for installation and 4 mills per kilowatt-hour for operation, for a total first-year cost of 8.8 mills per kilowatt-hour.[21]

- A 1983 OTA study estimated the average costs of scrubbing at the top 50 emitters to be $540 per ton of SOx.[22]

COSTS OF SWITCHING

Costs of switching would vary widely from one place to another depending upon the access of a plant to an economical source of low-sulfur coal, and the possibility of a low-sulfur coal premium. The following are attempts to calculate the costs of switching:

- EPRI figures from the survey cited above indicate that switching from Illinois coal to Power River Basin coal could remove SOx at costs between $394 and $553 per ton and with investments of $80 to $280 per kilowatt. These figures are about half the costs reported for scrubbing in this survey.

- CBO estimated the average costs of compliance with H.R. 4567 under a least-cost strategy to be $299 per ton. Because most of this reduction would be achieved by switching, this number could be taken as a close approximation of the average national costs of switching.[23]

- Calculations from data in the previously cited OTA study indicate the costs of using coal switching to comply with a 10-million ton reduction would be between $297 and $340 per ton. These estimates are about two-thirds the costs of scrubbing used by OTA in the same study.[24]

- A 1981 PEDCo study estimates the average costs of removing 6 million tons of SOx from the top 50 emitters through switching to be $250 per ton (1982 dollars).[25]

APPENDIX B:

KINDS OF CLEAN COAL TECHNOLOGIES

RETROFIT

ADVANCED COMBUSTION: A process designed to burn coal or coal-liquid mixtures directly in boilers originally designed for oil or gas. These combustors are suitable for conversion to coal or retrofitting.

ALTERNATE FUELS: Replacement of oil and gas fuels directly with coal-liquid mixtures (e.g., slurries), either in new sources or retrofits.

COAL PREPARATION: A process for mechanically, chemically, or biologically cleaning coal prior to combustion that reduces sulfur and ash content and upgrades the heat content of the fuel.

FLUE GAS CLEAN UP: A technology used mainly by utilities to remove SOx from post-combustion gases, usually by injection of a chemical sorbent into a "scrubber." It is highly efficient in removing SOx but often has high capital and maintenance costs.

IN-DUCT INJECTION: An addition to the pre-existing ductwork of a system which sprays a combination of lime and water into the post-combustion gas stream to remove SOx. This process could replace scrubbing especially in situations where there are space constraints.

REPOWERING

FLUIDIZED BED COMBUSTION: A boiler technology that relies on the combustion of a crushed coal and sorbent mixture, which is suspended by an injection of air and burned at a lower, controlled temperature. This technique is effective against both SOx and NOx emissions. It has mainly industrial and mid-sized utility applications.

HEAT ENGINES: Gas turbines and diesel engines that substitute coal or coal-derived liquids and gases for distillate fuels and natural gas.

HOT GAS CLEANUP: A process to clean gases derived from coal burning. These hot gases are used to drive electricity turbines. Gases must be cleaned to prevent impurities from damaging the turbines.

INTEGRATED GASIFICATION/COMBINED CYCLE: A generating technology that combines gasification, hot-gas cleanup, and heat engines. A coal gasifier at a power plant creates hot gas through combustion that first drives a gas turbine and then generates steam for a steam turbine.

GASIFICATION: The conversion of coal into high-quality gas through a process that can remove sulfur and particulates inexpensively. Products include fuel for industry, residential heating, utilities, and transportation (via indirect liquefaction) as well as chemical feedstocks. Gasification can be conducted either underground in the original coal seam, or on the surface at a gasification facility.

Table 1
COAL CONSUMPTION AND PRODUCTION TRENDS 1980-1985

Coal Consumed at Steam-Electric Plants 1980, 1982, 1984 and 1985[1]
(in millions of tons)

Region	1980	1982	1984	1985
Eastern U.S.[2]	525.2	508.4	586.7	561.1
(percent of total)	(88.4%)	(84.5%)	(85.8%)	(84.2%)
Western U.S.[2]	68.8	93.1	97.4	105.7
(percent of total)	(11.6%)	(15.5%)	(14.2%)	(15.9%)
Total	594.0	601.4	684.1	666.7

Coal Produced for Electric Utility Plants 1980, 1982, 1984, 1985[1]
(in millions of tons)

Region	1980	1982	1984	1985
Eastern U.S.[2]	405.6	395.5	448.2	416.7
(percent of total)	(68.3%)	(65.8%)	(65.5%)	(62.5%)
Western U.S.	187.4	205.4	235.2	248.7
(percent of total)	(31.5%)	(34.2%)	(34.4%)	(37.3%)
Imports	9.9	6.1	7.8	13.0
(percent of total)	(1.7)	(1.0%)	(1.2%)	(1.9%)
Total U.S.	594.0	601.4	684.1	666.7

[1]In 1980 and 1982 plants were included if they generated at least 25 megawatts. After 1982 plants were included if they generated at least 50 megawatts.

[2]Western U.S. equals sum of Pacific region, Mountain region and Dakotas, Eastern region constitutes the remainder.

SOURCE: Staff calculations from Department of Energy, Energy Information Administration, Cost and Quality of Fuels for Electric Utility Plants Volumes for 1980-1985.

Table 2
Labor Productivity - Average Production per Miner per Hour
(in short tons)

State or Region	1978	1980	1982	1984	1985
Illinois	1.76	1.86	1.97	2.22	2.14
Indiana	2.76	2.86	2.61	2.93	2.85
Ohio	1.57	1.46	1.63	2.01	2.02
Pennsylvania	1.36	1.41	1.40	1.67	1.65
Wyoming	7.64	8.99	11.06	13.77	14.34
Appalachian	NA[1]	1.39	1.51	1.86	1.90
Interior	NA[1]	2.30	2.38	2.80	2.81
Western	NA[1]	5.64	6.26	8.30	8.55
U.S. Total	1.79	1.93	2.11	2.64	2.74

[1]Regional aggregate data not available for 1978.

SOURCE: Department of Energy, Coal Production, Volumes 1978-1985.

Table 3
COAL INDUSTRY TRENDS

Coal Production
(in millions of tons)

State or Region	1978	1980	1982	1984	1985
Illinois	48.6	62.4	60.3	63.8	59.2
Indiana	24.2	31.0	31.7	37.5	33.3
Ohio	41.2	39.2	36.3	39.1	35.4
Pennsylvania	86.7	93.0	78.3	76.7	70.3
Wyoming	58.3	95.0	108.4	130.9	140.7
Eastern U.S.[1]	521.1	615.2	605.8	636.8	609.9
Western U.S.	149.0	210.5	226.7	253.8	268.6
Total U.S.	670.1	825.7	832.5	890.6	878.5

Coal Mining Employment
(in thousands)

State or Region	1978	1980	1982	1984	1985
Illinois	16.1	17.7	16.6	13.3	13.9
Indiana	4.6	5.3	5.5	5.5	5.2
Ohio	15.7	14.6	12.6	9.8	9.9
Pennsylvania	36.1	35.9	30.3	24.8	22.2
Wyoming	3.6	4.8	4.5	4.5	4.4
Eastern U.S.[1]	230.5	210.3	199.7	162.3	153.8
Western U.S.	11.8	18.2	17.5	15.5	15.5
Total U.S.	242.3	228.6	217.1	177.8	169.3

[1]Eastern U.S. equals the sum of Interior and Appalachian coal regions.

SOURCE: Department of Energy, Coal Production, Volumes 1978-1985.

Table 4
Coal Consumption Characteristics for Seven Importing States, 1978-1985

State/Year	Coal Consumption (in millions of tons)	Average BTUs per Pound	Average Sulfur Content (percent)	Rate of Potential Emissions (pounds per MM BTUs)	Cost (dollars per ton)	Cost (cents per MMBTUs)
Florida						
1978	7.3	11,789	1.97	3.17	34.63	146.9
1980	8.7	11,845	2.18	3.50	42.64	180.0
1984	15.6	12,228	1.80	2.80	52.99	216.7
1985	17.5	12,225	1.80	2.80	51.84	212.0
Georgia						
1978	17.0	11,874	1.75	2.80	29.70	125.1
1980	21.3	11,902	1.85	2.95	35.71	150.0
1984	28.6	12,125	1.80	2.82	46.73	192.7
1985	26.3	12,120	1.80	2.82	45.53	187.8
Michigan						
1978	20.1	11,549	1.84	3.03	29.72	128.7
1980	22.1	12,012	1.30	2.06	37.57	156.4
1984	25.1	11,670	1.20	1.95	44.66	191.3
1985	24.1	11,696	0.80	1.30	43.96	187.9
Missouri						
1978	20.6	10,745	2.68	4.74	21.60	100.5
1980	24.8	10,653	2.62	4.67	25.32	118.8
1984	27.4	10,707	2.60	4.61	32.02	149.5
1985	22.2	10,645	2.40	4.28	31.98	150.2
North Carolina						
1978	19.3	12,026	1.08	1.71	33.28	138.4
1980	23.4	12,269	0.96	1.49	38.46	156.7
1984	20.0	12,477	0.90	1.37	48.62	194.8
1985	19.7	12,487	0.90	1.37	49.34	197.6
Tennessee						
1978	21.2	11,283	2.47	4.16	26.99	119.6
1980	21.8	11,627	2.26	3.69	36.21	155.7
1984	20.6	11,805	1.90	3.06	38.30	162.2
1985	18.7	11,829	1.90	3.05	36.34	153.6
Wisconsin						
1978	11.8	10,451	2.15	3.91	23.90	114.3
1980	14.5	10,262	1.87	3.46	29.09	141.7
1984	15.5	9,954	1.50	2.86	34.18	171.7
1985	15.3	9,774	1.10	2.14	33.35	170.6
United States						
1978	476.2	10,638	1.79	3.20	23.75	111.6
1980	594.0	10,647	1.60	2.86	28.76	135.1
1984	684.1	10,552	1.50	2.70	35.12	166.4
1985	666.7	10,480	1.40	2.54	34.53	164.7

SOURCE: Department of Energy, Cost and Quality of Fuels for Electric Utility Plants, 1978, 1980, 1984, and 1985.

Table 5
Decrease in Potential Emissions Due to Decline in Average Sulfur Content of Coal, 1978-85
(thousands of tons)

State	Potential Emissions in 1978[1]	Potential Emissions in 1985	Potential Emissions if Coal in 1985 Had Sulfur Content of Coal in 1978	Change in Potential Emissions Due to Change in Sulfur Content of Coal[2]
Florida	273	599	655	-56
Georgia	565	899	874	25
Michigan	703	366	843	-477
North Carolina	396	337	404	-67
Missouri	1,049	1,012	1,130	-118
Tennessee	995	675	878	-203
Wisconsin	482	320	625	-305
Subtotal	4,463	4,208	5,409	-1,201
U.S. Total	16,196	17,734	22,674	-4,940

[1]1978 statistics cover electric utilities with capacities of 25 MW or greater. 1985 statistics cover electric utilities with capacities of 50 MW or greater.

[2]Comparisons are subject to a 5 percent margin of error due to changes in Department of Energy rounding.

SOURCE: Department of Energy, Cost and Quality of Fuels for Electric Utility Plants, 1978 and 1985.

Table 6
Coal Production and Consumption for the Electric Utility Sector in 1985
(millions of tons)

State	Total Production of Coal	Total Consumption of Coal	Coal Consumption Produced In-State	Coal Exported to Other States	Coal Imported from Other States	Coal Exports Minus Coal Imports
			Net Coal Importers			
Alabama	16.6	20.5	14.7	1.9	5.8	-3.9
Florida	0.0	17.5	0.0	0.0	17.5	-17.5
Georgia	0.0	26.3	0.0	0.0	26.3	-26.3
Indiana	25.0	36.8	17.6	7.3	19.2	-11.9
Michigan	0.0	24.5	0.0	0.0	24.5	-24.5
Missouri	4.7	22.2	3.9	0.8	18.3	-17.5
North Carolina	0.0	19.7	0.0	0.0	19.7	-19.7
Ohio	32.8	44.5	23.8	9.0	20.7	-11.7
Tennessee	4.4	18.7	1.8	2.6	16.9	-14.3
Wisconsin	0.0	15.3	0.0	0.0	15.3	-15.3
			Net Coal Exporters			
Illinois	54.2	31.1	16.3	37.9	14.8	23.1
Kentucky	111.0	24.7	21.1	89.9	3.6	86.3
Pennsylvania	43.9	39.3	30.0	13.9	9.3	4.6
West Virginia	64.7	27.8	26.1	38.6	1.7	36.9
Subtotal	357.3	368.9	155.3	201.9	213.6	
U.S. Total	666.7					

SOURCE: Department of Energy, Cost and Quality of Fuels for Electric Utility Plants, 1985, July 1986.

Table 7
Characteristics of Major Eastern Coal Consuming and Producing States, 1985

Coal User Category[1]	State Production of Its Own Utility Coal Consumption			
	100-67 Percent	66-34 Percent	33-1 Percent	None
Coal Importers	Alabama	Indiana Ohio	Tennessee Missouri	Florida Georgia Michigan North Carolina Wisconsin
Coal Exporters (less than 50 percent of total production)	Pennsylvania			
Coal Exporters (greater than 50 percent of total production)	Kentucky West Virginia	Illinois		

[1]Although all of the coal producing states both import and export coal to some degree, coal importers and exporters are defined here as those that are either **net** importers or **net** exporters of coal.

SOURCE: Calculations by Northeast-Midwest Institute staff from the Department of Energy, Cost and Quality of Fuels for Electric Utility Plants, 1985.

Table 8
Reductions in Emissions of SO_x Required Under H.R. 4567
(thousands of tons)

	Base Level of Emissions			State Plan Reductions			Default Reductions		
	ICF (2000)	CBO (1995)	OTA (1980)	ICF (2000)	CBO (1995)	OTA (1980)	ICF (2000)	CBO (1995)	OTA (1980)
Illinois	998	1,142	1,126	-530	-624	-709	-597	-739	-754
Indiana	1,866	1,433	1,540	-1,223	-826	-1,173	-1,291	-876	-1,177
Ohio	2,816	2,017	2,172	-1,863	-1,313	-1,600	-1,997	-1,376	-1,611
Pennsylvania	1,162	1,439	1,466	-543	-724	-880	-643	-873	-907
Subtotal	6,842	6,031	6,304	-4,159	-3,487	-4,362	-4,528	-3,864	-4,449
U.S. Total	20,529	18,455	17,325	-8,133	-8,317	-9,952	-10,381	-9,114	-10,508

SOURCES: ICF, August, 1986; Congressional Budget Office, June 1986; Office of Technology Assessment, April 9, 1986 and May 9, 1986.

Table 9
Reductions in Emissions of NO_x Required Under H.R. 4567
(thousands of tons)

	Base Level of Emissions (year 2000)	State Plan Reductions	Default Reductions
Illinois	947	-174	-174
Indiana	1,810	-186	-189
Ohio	2,738	-208	-252
Pennsylvania	1,290	-73	-87
Subtotal	6,785	-641	-702
U.S. Total	19,655	-2,036	-2,669

SOURCE: ICF, August, 1986.

Table 10
Cost of Control for Different SO_x Emission Reduction Levels

Emission Reduction Levels (millions of tons per year)	Total Cost of Program by 2015 (billions of 1985 dollars)	Cost Effectiveness (dollars per ton SO_x removed)	Change in Coal Production in the Four-State Region[1] (millions of tons per year)	Change in Coal Mining Employment in the Four-State Region[1] in 1985
8.0	20.4	270	-48.3	-14,100
9.1[2]	25.9	299	-57.7	-17,000
10.0	34.5	360	-74.6	-21,900
12.0	93.6	779	-45.8	-13,400

[1] Illinois, Indiana, Ohio, Pennsylvania.
[2] Equivalent to H.R. 4567. H.R. 2666 would result in a 10 million ton reduction.

SOURCE: Congressional Budget Office, June, 1986.

Table 11
Increases in Annual Utility Costs
Due to SO_x Control Under H.R. 4567
(millions of dollars)

	State Plan		Default	
	ICF (2000)	CBO (1995)	ICF (2000)	CBO (1995)
Illinois	69	139	231	132
Indiana	382	158	544	170
Ohio	462	259	843	84
Pennsylvania	345	472	487	316
Subtotal	1,258	1,028	2,105	702
U.S. Total	2,485	2,489	5,545	3,310

SOURCES: ICF, August, 1986; Congressional Budget Office, June, 1986.

Table 12
Increases in Annual Utility Costs for Controlling SO_x Compared to NO_x Under H.R. 4567
(millions of dollars)

	State Plan			Default		
	SO_x	NO_x	Total	SO_x	NO_x	Total
Illinois	69	130	199	231	184	415
Indiana	382	19	401	544	139	683
Ohio	462	21	483	843	96	939
Pennsylvania	345	5	350	487	22	509
Four-State Subtotal	1,258	175	1,433	2,105	441	2,546
U.S. Total	2,485	339	2,824	5,545	1,490	7,035

SOURCE: ICF, July 3, 1986.

Table 13
Residential Electricity Rate Increases Due to H.R. 4567
(in percent)

	State Plan			Default		
	ICF	OTA	CBO	ICF	OTA	CBO
Illinois	2.1	3.0	3.2	4.3	3.0	5.6
Indiana	7.6	11.0	2.6	12.9	11.0	4.8
Ohio	4.9	7.0	3.8	9.6	7.0	4.7
Pennsylvania	3.6	5.0	1.9	5.2	5.0	4.8
U.S. Total	--	2.0-3.0	1.5	--	2.0-3.0	2.1

SOURCES: ICF, August, 1986; Congressional Budget Office, June, 1986; Office of Technology Assessment, April 9, 1986.

Table 14
Effect of H.R. 4567 on Coal Mining Employment in a Four-State Region[1]

State	UMW	CBO	ICF
Illinois	-3,879	-3,807	-9,900
Indiana	-1,582	-987	-1,600
Ohio	-5,030	-5,953	-6,100
Pennsylvania	-8,484	-6,215	-900
Total	-18,975	-16,962	-18,500

[1]Assumes use of state plans. UMW and CBO figures are for 1995. ICF figures are for the year 2000.

SOURCES: United Mine Workers, April, 1986; Congressional Budget Office, June, 1986; ICF, August, 1986.

Table 15
Changes in Annual State Income as a Result of Coal Switching Under H.R. 4567

	Change in Production of Coal by 1995 (millions of tons)	Price per Ton in 1985 (dollars)	Change in Income in 1995 (millions of dollars)
Illinois	-14.6	36.80	-537
Indiana	- 5.4	31.93	-172
Ohio	-20.3	40.46	-821
Pennsylvania	-17.4	38.06	-662
Subtotal	-57.4	--	-2,192
Wyoming	+38.6	29.20	+1,127

SOURCE: Calculations by Northeast-Midwest Institute staff from Congressional Budget Office, June 1986.

Table 16
Comparative Costs of Clean Coal Technologies

Control Technology	Emission Reductions		Power Plant Effects		Incremental Costs	
	SOx	NOx	Power Output	Plant Life	Mills/Kwh	Dollars/Kw
CONVENTIONAL CONTROL						
Flue-Gas Cleanup	90%	--	Moderate Decrease	No Change	9-11	180-200
INNOVATIVE RETROFITING						
Pre-combustion						
• Advanced Coal Cleaning	30-90%	--	No Change	Small Increase	6-21	--
Combustion						
• LIMB	50-60%	50-70%	Small Decrease	No Change	5-8	80-90
• Slagging Combustor	50-90%	50-70%	Small Decrease	Small Increase	1-2	50-60
Post-combustion						
• Duct Injection/Gas Reburn	55-75%	Moderate	Small Decrease	Small Increase	2-4	50-110
INNOVATIVE REPOWERING						
Fluidized Bed						
• Atmospheric	85-90%	Moderate	10-15% Increase	Moderate Increase	6-8	700-900[1]
• Pressurized	90-95%	Moderate	40-50% Increase	Moderate Increase	4-6	800-1000[1]
Integrated Gasification Combined Cycle	95-99%	Moderate	50-150% Increase	Moderate Increase	1-2	1100-1300[1]

[1]Total cost of repowering including nonenvironmentally related investments in increased power generation.

SOURCE: Department of Energy, America's Clean Coal Commitment: Appendix A, February 1987.

Table 17
Retrofit Scrubber Costs for Utilities
Using High Sulfur Coal
(greater than 1 percent sulfur content)

Name of Unit	Net Generating Capacity by Unit (Megawatts)	Year of Retrofit	Sulfur Content of Coal (in percent)	Sulfur Removal Efficiency (in percent)	Installed Costs (dollars per KW)	Operation and Maintenance (mills per KWH)
Duquesne Light						
Elrama 1-4	487	1975	2.05	83	187.8	12.89
Philips 1-6	373	1973	2.05	83	210.0	17.65
Kentucky Light						
Green River 1-3	59	1975	2.23	98	117.8	10.99
Louiville Gas and Electric						
Cane Run 4	175	1776	3.87	85	115.2	6.20
Cane Run 5	192	1977	3.80	85	102.4	5.30
Cane Run 6	277	1979	4.80	95	87.8	7.23
Mill Creek 1	334	1980	3.75	85	60.4	4.23
Tennessee Valley Authority						
Widows Creek 8	516	1977	3.30	80	158.1	7.28

SOURCE: U.S. Department of Energy, Cost and Quality of Fuels for Electric Utility Plants, 1985. July 1986.

Footnotes

1. U.S. Congress, Congressional Budget Office, The Clean Air Act, the Electric Utilities, and the Coal Market (Washington, D.C., April, 1982), p. 40; U.S. Department of Energy, Energy Information Administration, Annual Outlook for U.S. Coal: 1985 (Washington, D.C., May 1985), p. 19.

2. U.S. Department of Energy, Energy Information Administration, Coal Production annuals for 1981 and 1985, (Washington, D.C., 1982 and 1986), passim. Between 1981 and 1985 the price of Wyoming coal declined 4.0 percent, while it rose by 12.0 percent in Illinois and 16.7 percent in Ohio.

3. Since one atom of sulfur combines with two atoms of oxygen to create SO_2, the quantity of sulfur has been multiplied by 1.9 in order to calculate the potential rate of emissions. No retention of sulfur in ash has been assumed. This comparison of potential emissions exaggerates somewhat the actual impact of coal switching, because utilities during this period removed some sulfur with other methods. However, this comparison does indicate that the overall potential impact of coal switching is quite large.

4. For a discussion of the effects of rail rates on consumers and shippers see Mark Cooper, testimony for the Consumer Federation of America, Hearings before the Senate Subcommittee on Surface Transportation of the Science and Transportation Committee, (100th Congress, 1st session), June 17, 1987; and John Paul, statement on behalf of the National Coal Association and the American Mining Congress, Hearings before the Senate Subcommittee on Surface Transportation of the Science and Transportation Committee, (100th Congress, 1st session), June 17, 1987. For an opposing point of view, see the Association of American Railroads, Economics and Finance Department, Railroad Freight Rates in the Five Years Since Staggers (Washington, D.C., February, 1986).

5. The authors of all three studies believed that innovative technologies were still approaching commercialization, and that reliable data on their probable performance was not yet available. Projections in these studies must be treated with considerable caution, especially state-level data. Use of different assumptions in economic models can cause estimated effects to vary widely. Within these limitations, however, some valid projections can be made of the economic effects of controls on the Eastern coal region.

6. ICF Incorporated, "Analysis of HR-4567: National and Regional Forecasts," Memorandum to the Environmental Protection Agency, July 3, 1986, p. 3.

7. Northeast-Midwest Institute staff calculations from Air Pollution Control Association, Product Guide/1984, reprinted from APCA Journal, Vol. 34, No. 3, March 1984; U.S. Department of the Interior, Bureau of Mines, "Lime Plants in the United States," in Mineral Energy Surveys (Washington, D.C., June 12, 1984), passim. For a study of secondary economic effects on coal communities from a loss of coal mining employment, see Larry Parker, Mitigating Acid Rain: Implications for High-Sulfur Coal Regions (Washington, D.C.: Congresional Research Service, May 16, 1983). For a macroeconomic projection of net employment effects of acid rain control

legislation, see Management Information Services, Inc., The Net Costs and Benefits to Each State and to the Nation of Acid Rain Control Legislation (Washington, D.C., February, 1987). For a critique of the MIS report see Temple, Barker, and Sloane, "MIS report on Jobs Impact," February 17, 1987.

8. Some of the material contained in this section has been published in a previous report by the Northeast-Midwest Institute. See Wesley Warren, Lewis-Davis and Acid Rain: An Evaluation (Washington, D.C., revised April 17, 1987), pp. 5-9.

9. Dr. Sun W. Chun, Director, Pittsburgh Energy Technology Center, Department of Energy, "Emerging Technologies for the Control of SOx Emissions," Address before the Washington Coal Club, Washington, D.C., January 14, 1987, p. 6.

10. Kurt Yeager, Vice President, Coal Combustion Systems Division, and Gene Mannella, Director, Washington Office, Electric Power Research Institute, Statement before the House of Representatives Subcommittee on Energy Development and Applications of the Committee on Science and Technology, (99th Congress, 2nd session), March 4, 1986; Kurt Yeager, Statement before the Senate Committee on Energy and Natural Resources, (99th Congress, 2nd session), June 10, 1986.

11. Energy Ventures Analysis, Inc., Evaluation of SO2 Emissions and the FGD Retrofit Feasibility at the 200 Top Emitting Generating Stations (Washington, D.C., January 10, 1986), pp. 2-9. This study by Energy Ventures Analysis, Inc. divided the units of the 120 top emitting power plants into four categories according to their ability to retrofit a scrubber: easy, modest, difficult, and very difficult. Emissions of SOx from these power plants totaled 11.6 million tons in 1980. Units in the easy-to-retrofit category accounted for 3.3 million tons, while the units in the modest-retrofit group added another 3.0 million tons.

12. U.S. Department of Energy, Energy Information Administration, State Energy Price and Expenditure Report 1984 (Washington, D.C., September 22, 1986), p. xi; Energy Information Administration, Electric Power Annual 1985 (Washington, D.C., July 18, 1986), p. 10; and Energy Information Administration, U.S.-International Electricity Trade (Washington, D.C., September 22, 1986), p. viii.

13. Drew Lewis and William Davis, Joint Report of the Special Envoys on Acid Rain (Washington, D.C., January, 1986), p. 6 and pp. 29-30.

14. In the previously mentioned study for EPA by Energy Ventures Analysis, Inc., in the states of Illinois, Indiana, Ohio, and Pennsylvania, units that were rated easy to scrub had a median age of 15 years; units that were modestly difficult, 19 years; difficult, 30 years; and very difficult, 32 years.

15. For discussions of various life-cycling proposals, especially 30 year/1.2 pounds, see ICF Incorporated, Analysis of 6 and 8 Million Ton and 30 Year/NSPS and 30 Year/1.2 Lb. Sulfur Dioxide Emission Reduction Cases (Washington, D.C. February, 1986); John McCormick, Statement before the House of Representatives Subcommittee on Fossil and Synthetic Fuels of the

Energy and Commerce Committee, (99th Congress, 2nd session), March 20, 1986; and Eugene Trisko, "Implications of Utility Life Extension for the Acid Rain Control Debate," Presentation for the 80th Annual meeting and Exhibition of the Air Pollution Control Association, New York, New York, June 21-26, 1987.

16. ICF Incorporated, Analysis of 6 and 8 Million Ton and 30 Year/NSPS and 30 Year/1.2 Lb. Sulfur Dioxide Emission Reduction Cases, p. D-11. According to ICF, an acid rain control plan that relied simply on 30 year/1.2 lb., including the use of bubbling, would reduce SOx emission by 3.3 million tons in 1995, 6.0 million in 2000, and 11.0 million in 2010. An interesting feature of 30 year/1.2 lb. is the reduction in emissions that the plan continues to achieve in the long-term, when some other acid rain control plans would begin to see a rise in emissions again.

17. Kurt Yeager, "Coal Utilization Technologies of the Future," in Coal Technology '85, Vol. I, Conference papers from the 8th International Coal and Solid Fuels Utilization Exhibition and Conference, Pittsburgh, Pennsylvania, November 12-14, 1985, (Houston, Texas: Industrial Presentations, Inc., 1986), p. 39.

18. American Electric Power, Analysis of the Impact on the AEP System of Compliance with H.R. 4567: "The Acid Deposition Control Act of 1986" (Washington, D.C., July 1986), p. 8.

19. Michael High, "The Tennessee Valley Authority's (TVA) Sulfur Dioxide Emission Reduction Program," in Acid Rain: Clouds over the Midwest (Washington, D.C.: National Clean Air Fund, 1986), Conference proceedings, Chicago, Illinois, March 7-8, p. 137.

20. Industrial Gas Cleaning Institute, Acid Rain Control Briefing Document on Retrofitting Flue Gas Desulfurization Systems to Existing Coal-Fired Boilers (Washington, D.C., July 1987), p. 2.

21. U.S. Congress, Congressional Budget Office, Curbing Acid Rain? Cost, Budget, and Coal-Market Effects (Washington, D.C., June 1986), p. 14.

22. U.S. Congress, Office of Technology Assessment, "Additional Analyses of H.R. 3400, 'The National Acid Deposition Control Act of 1983,'" staff memorandum, September 16, 1983, p. 17.

23. CBO, Acid Rain, p. xxiii.

24. OTA, "Additional Analyses," p. 13. This calculation is derived by Northeast-Midwest staff by dividing the additional costs of mandating scrubbing at the top 50 emitting plants ($1.3 to $1.6 billion) by the amount of SOx removed (6.5 million), and subtracting the quotient ($200 to $243 per pound of SOx) from the estimated costs of scrubbing ($540 per pound of SOx).

25. Referenced in OTA, Acid Rain and Transported Air Pollutants (Washington, D.C., June 1984), p. 158.

Bibliography

Air Pollution Control Association. Product Guide/1984. Reprinted from APCA Journal, Vol. 34, No. 3, March 1984.

American Electric Power. Analysis of the Impact on the AEP System of Compliance with H.R. 4567: "The Acid Deposition Control Act of 1986." Washington, D.C., July 1986.

Association of American Railroads. Economics and Finance Department. Railroad Freight Rates in the Five Years Since Staggers. Washington, D.C., February 1986.

Chun, Sun W. Director, Pittsburgh Energy Technology Center, Department of Energy. "Emerging Technologies for the Control of SOx Emissions." Address before the Washington Coal Club, Washington, D.C., January 14, 1987.

Cooper, Mark. Testimony for the Consumer Federation of America. Hearings before the Senate Subcommittee on Surface Transportation of the Science and Transportation Committee. June 17, 1987.

Energy Ventures Analysis, Inc. Evaluation of SO2 Emissions and the FGD Retrofit Feasibility at the 200 Top Emitting Generating Stations. Washington, D.C., January 10, 1986.

ICF Incorporated. Analysis of 6 and 8 Million Ton and 30 Year/NSPS and 30 Year/1.2 Lb. Sulfur Dioxide Emission Reduction Cases. Washington, D.C., February 1986.

_____. "Analysis of HR-4567: National and Regional Forecasts," Memorandum to the Environmental Protection Agency. Washington, D.C., July 3, 1986.

_____. An Economic Analysis of HR 4567 The Acid Deposition Control Act of 1986. Washington, D.C. August 1986.

Industrial Gas Cleaning Institute. Acid Rain Control Briefing Document on Retrofitting Flue Gas Desulfurization Systems to Existing Coal-Fired Boilers. Washington, D.C., July 1987.

Jessup, Philip. Opportunities for Reducing the Costs of Acid Rain Controls: Commercialization of Clean Coal Technologies. Unpublished report. June 8, 1987.

Lewis, Drew, and William Davis. Joint Report of the Special Envoys on Acid Rain. Washington, D.C., January 1986.

Management Information Services, Inc. The Net Costs and Benefits to Each State and to the Nation of Acid Rain Abatement Legislation. Washington, D.C., February 1987.

McCormick, John. Environmental Policy Institute. Statement before the House of Representatives Subcommittee on Fossil and Synthetic Fuels of the Energy and Commerce Committee. March 20, 1986.

National Clean Air Fund. Acid Rain Clouds over the Midwest: Science and Solutions. Conference Proceedings, Chicago, Illinois, March 7 and 8, 1986. Washington, D.C., 1986.

Parker, Larry. Acid Rain: Issues in the 100th Congress. Washington, D.C.: Congressional Research Service, February 11, 1987.

_____. Mitigating Acid Rain: Implications for High-Sulfur Coal Regions. Washington, D.C.: Congressional Research Service, May 16, 1983.

Paul, John. Statement on behalf of the National Coal Association and the American Mining Congress. Hearings before the Senate Subcommittee on Surface Transportation of the Science and Transportation Committee. June 17, 1987.

Temple, Barker, and Sloane. "MIS Report on Jobs Impacts." Memorandum to the Edison Electric Institute. February 17, 1987.

Trisko, Eugene. "Implications of Utility Life Extension for the Acid Rain Control Debate." Presentation for the 80th Annual meeting and Exhibition of the Air Pollution Control Association. New York, New York, June 21 to 26, 1987.

United Mine Workers. The Acid Deposition Control Act of 1986, H.R. 4567: Economic and Employment Consequences. Washington, D.C., 1986.

U.S. Congress. Congressional Budget Office. The Clean Air Act, the Electric Utilities, and the Coal Market. Washington, D.C., April 1982.

_____. Congressional Budget Office. Curbing Acid Rain: Cost, Budget, and Coal-Market Effects. Washington, D.C., June 1986.

_____. Office of Technology Assessment. Acid Rain and Transported Air Pollutants. OTA-O-204. Washington, D.C., June 1985.

_____. Office of Technology Assessment. "Additional Analysis of H.R. 3400, 'The National Acid Deposition Control Act of 1983.'" September 16, 1983.

_____. Office of Technology Assessment. "An Analysis of a 1986 Acid Rain Control Proposal in Response to Congressman Henry Waxman." April 9, 1986.

_____. Office of Technology Assessment. "An Analysis of the Sikorski/Waxman Acid Control Program: H.R. 3400, 'The National Acid Deposition Control Act of 1983.'" Revised July 12, 1983.

_____. Office of Technology Assessment. New Electric Power Technologies. OTA-E-246. Washington, D.C., July 1985.

_____. Office of Technology Assessment. "Responses to Questions about H.R. 4567 from Congressman John Dingell." May 9, 1986.

U.S. Department of Energy. Energy Information Administration. Annual Outlook for U.S. Coal 1985. DOE/EIA-0333(85). Washington, D.C., May 1985.

_____. Energy Information Administration. Coal Production 1985. DOE/EIA-0118(85). Washington, D.C., November 1986.

_____. Energy Information Administration. Cost and Quality of Fuels for Electric Utility Plants 1985 DOE/EIA-0191(85). Washington, D.C., July 1986.

_____. Energy Information Administration. Electric Power Annual 1985. DOE/EIA-0348(85). Washington, D.C., July 18, 1986.

_____. Energy Information Administration. State Energy Price and Expenditure Report 1984. DOE/EIA-0379(84). Washington, D.C., September 22, 1986.

_____. Energy Information Administration. U.S.-International Electricity Trade. DOE/EIA-0496. Washington, D.C., September 22, 1986.

_____. Office of Fossil Energy. America's Clean Coal Commitment. Washington, D.C., February, 1987.

U.S. Department of the Interior. Bureau of Mines. "Lime Plants in the United States." In Mineral Energy Surveys. Washington, D.C., June 12, 1984.

U.S. Office of the Director of Research. National Acid Precipitation Assessment Program Annual Report, 1985. Washington, D.C: Interagency Task Force on Acid Precipitation, 1985.

Warren, Wesley. Clean Coal Technologies and Acid Rain. Washington, D.C.: Northeast-Midwest Institute, March 1986.

_____. Clean Coal Technology Reserve. Washington, D.C.: Northeast-Midwest Institute, April 1985.

_____. Lewis-Davis and Acid Rain: An Evaluation, Washington, D.C.: Northeast-Midwest Institute, April 1987.

Yeager, Kurt. Vice President, Coal Combustion Systems Division, Electric Power Research Institute. Statement before the Senate Committee on Energy and Natural Resources. June 10, 1986.

_____. Vice President, Coal Combustion Systems Division, and Gene Mannella, Director, Washington Office, Electric Power Research Institute. Statement before the House of Representatives Subcommittee on Energy Development and Applications of the Committee on Science and Technology. March 4, 1986.

_____. "Coal Utilization Technologies of the Future." Coal Technology '85. Conference papers from the 8th International Coal and Solid Fuels Utilization Exhibition and Conference, Pittsburgh, Pennsylvania, November 12-14, 1985. Houston, Texas: Industrial Presentations, Inc., 1986.